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January 14, 2005

Docket Control
Arizona Corporation Commission
1200 W. Washington Avenue
Phoenix, Arizona 86007

Subject: Docket # E-01345A-03-0437
Brief from AZCA

Dear Sir/Madam:
Enclosed is the Brief from the Distributed Generation Association of Arizona (DEAA), aka AZCA.
Unfortunately we have been unable to provide references to the examination and cross-examination of witnesses as the 20 page limit at Docket Control was too limiting and we could not afford the approximately $4,000 cost of the complete transcript.
However, we do believe that our referencing in the attached 'Brief' does provide adequate support for our testimony.

If you should have any questions please call me on (602) 703-8163 /(602) 703-8156 or email me at billmurphy@cox.net.

William J. Murphy
Vice President of the DEAA

Cc: Docket Control (original and 13 copies)
Email sent to parties

Arizona Corporation Commission
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DISTRIBUTED ENERGY ASSOCIATION OF ARIZONA BRIEF

ACC DOCKET # E-01345A-03-0437

SUBMITTED JANUARY 14, 2005

DEAA BRIEF ON APS SETTLEMENT (DOCKET #E-01345A-O3-0437)

This Commission has been presented with a complex and far-reaching proposed settlement that will have effects for many years on the electricity future of Arizona. The members of DEAA acknowledge the Arizona Corporation Commission and express its appreciation for the level of involvement we have seen from all of the Commissioners.

Why should the Commission be concerned with Distributed Generation? There are cases where Arizona Public Service has insufficient power in load pockets or requires expansion into pristine or densely populated areas. New substations and transmission lines may be able to be avoided.

It is possible that these new facilities might not be required if loads at existing substations were reduced by Distributed Generation (DG) at existing commercial or industrial facilities

This case presents this Commission with broad public policy questions and implications. The DEAA believes that a "good" decision that meets the Commission's public policy objectives should be guided by the following overriding criteria:

I. **Rates must be fair; as cost-based as possible; and should not discriminate against one or more customers**

II. **Rates should be designed to send as efficient-as-possible pricing signals to consumers**

III. **Impediments to Customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible**

IV. **All generators should be treated fairly – large and small**

V. **Proposals, if implemented, should not interfere with the Commission's public policy goals.**

Regrettably, the proposed settlement fails to meet each and every one of these criteria. In its testimony and under cross-examination, in the testimony of its witnesses, the DEAA presented several reasons why this Commission should reject the tariff revisions in the settlement that pertain to customers with their own generation. The DEAA continues to request that this Commission reject these changes OR, at least incorporate the changes that the DEAA proposes herein.

DEAA was an active participant in the Settlement process, but is not a signatory to the agreement because <u>the settlement – simply put – represents a giant step backwards for customer-owned generation as well as certain renewable projects</u>. While the other parties discuss the almost biblical success of the settlement, the DEAA stands alone – wondering why on-site generation was dealt such a blow.

Fortunately, the DEAA believes the settlement can, in some cases, be modified to address it shortcomings. In other areas of the settlement, the DEAA is recommending that further action be taken through workshops, managed by Staff or through other appropriate means. These recommendations are presented later.

DISCUSSION

CRITERIA I - Rates must be fair; as cost-based as possible; and should not discriminate against one or more customers class(es).

<u>Rate E-32</u>

A prima facie case can be made that the proposed APS rates for partial requirements service are discriminatory based solely on Mr. Chamberlain's analysis that a 500 kW <u>partial requirements customer</u> on the proposed E32R/32 would pay higher annual charges than an identical partial requirements customer on Consolidated Edison's rate SC-14-RA. (p. 6, lines 9-11).[1] If the rates being proposed in the settlement for full service APS customers were higher than the equivalent rate for Con Ed customers, it seems highly unlikely that a settlement would have been reached at all.

In addition the settlement contains more obvious and explicit discriminatory treatment towards partial requirements customers.. For example, rate E-32R imposes substantially higher minimum charges on partial requirements customers taking service under essentially E-32 than are imposed upon other full requirements E-32 customers. This occurs regardless of how much generation a customer installs in relation to its peak load.

As an example, a 400 kW E-32 customer that installs a 25 kW generator to back up critical loads will increase his minimum bill from $700 per month (400 kW times $1.75 per kW) to over $1800 (100 kW x $7.722 plus 300 x 3.497) simply because of the 25 kW generator. That adds a potential MONTHLY cost of over $72 per kW for standby service to the cost of operating the generator.

A partial requirements customer is NOT simply a lower load factor customer. A low load factor customer expects to have service available to serve its peak load, usually around the time of the system peak, based on its normal load profile. In contrast, a partial requirements customer that normally provides a portion or all of its load – particularly during high cost peak hours – only needs service if and when its on-site generator goes down unexpectedly. This is not unlike APS's own generation.

[1] Mr. Rumolo of APS attempted to refute Mr. Chamberlain's statement but failed. Mr. Rumolo did not accurately represent (and, perhaps, did not fully understand) how a supply charge mechanism in the Con Ed tariff works. A partial requirements customer on Con Ed's tariff is assessed supply charges based on the customer's contribution to the transmission system's peak load in its peak hour of the previous summer. Thus if a customer's generator is operating and serving customer load at the time of Con Ed's system peak – which is highly probable because the rate design sends much better price signals than the proposed APS rates – that customer avoids any obligation to purchase ANY fixed supply charges for the load that backs up the on-site generator..

As Mr. Chamberlain pointed out in his testimony, APS plans its generation requirements based on projections of peak load and the likely availability of its generation resources. APS plans for generating capacity in excess of its peak load to account for unexpected plant outages based on the likelihood that resources will be forced out of service. APS does not assume that ALL generating resources will be unavailable at the same time. Rather, APS assumes that there will be considerable diversity in the forced outages of its facilities.

APS did not dispute Mr. Chamberlain's testimony that APS's rates for partial requirements customers do not reflect any diversity in the forced outages of their generators on a customer class basis. Put differently, rates for partial requirements customers were developed assuming that all on-site generators are forced out at the time of the system peak. (Chamberlain, p. 5, lines 15-19) It should be noted that rates for full service customers don't even make the assumption that all customers will be consuming at their respective peak demand levels at the time of the system peak.

CRITERIA II - Rates should be designed to send as efficient-as-possible pricing signals to consumers

E-32

No one has disputed Mr. Murphy's testimony that there is little understanding by the APS customers of demand charges ($/kW/Month). These charges are based on a the highest load levels experienced in any moving 15 minute period at **anytime** during the month. The time of the monthly peak is unknown by the customer or APS.

Rate E-32 is used by 94% of all General Service (GS) customers. The proposed rate E-32 has included a 2 to 3 fold increase in demand charges (kW/mo) coupled with a significant reduction in the cost of energy (¢/kWh). As discussed in the DEAA testimony these changes will greatly reduce the incentives for energy conservation, DSM, and DG. None of the parties have disputed this conclusion.

The key to this impact on DG is that the increased demand is to double and triple the cost of standby charges and increased the cost of supplemental energy.. This eliminates E-32R, E-51, and E-52 as economic choices for potential DG customers.

Mr. Chamberlain's testimony noted the following:

> The rate structures proposed for partial requirements customers produce perverse incentives to <u>increase</u> on peak energy use and do nothing to encourage (and may, in fact, penalize) load management efforts to shift load to off peak periods. (p. 2, lines 25-28)

No party disputes that rate E-32 does NOT differentiate between on and off peak hours of the day or that it does NOT differentiate as to which hour a customer's billing demand is established. As a result, a partial requirements customer that operates its generation on-peak and scales it back during the off-peak hours sees no savings for avoiding on-peak purchases. As Mr. Chamberlain later indicated in his testimony:

> <u>An E-32 customer operating solely during off-peak hours with a peak load of 500 kw would pay the same total demand and non-fuel energy charges as a customer operating during only on-peak hours.</u> *(no emphasis added)*

APS witness Rumolo's response was essentially "so what?"[2]

Mr. Chamberlain raises another undisputed point in his testimony:

> As a result, a[E-32] customer has no clear incentive to avoid consumption at the system peak. (p. 8, lines 30-31).

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[2] See Settlement Rebuttal Testimony of David J. Rumolo; p9-10

Rate E-32 charges a customer consuming energy and demand at the hour of the APS system peak exactly the same rates as a customer consuming energy and demand at 3 am in the morning. As Mr. Chamberlain pointed out in his testimony, the cost of operating a business during off-peak hours is more expensive and more difficult than operating during peak hours, including shift wage differentials, utilities and supervision. An efficiently run business would never choose to operate during the night – at higher costs – and not expect to realize electricity cost savings.

No party has disputed that it is more expensive for APS to meet peak load than off-peak load. Inexplicably, E-32 makes no distinction. In fact, the cost of energy drops well below the marginal price of production after the customer consumes 200 kwhrs per kW of monthly peak. This second "block" energy rate is based on the weighted average cost of all energy produced or purchased by APS. Thus, it is reasonable to conclude that all of the energy consumed in the second block during <u>peak hours</u> costs more to produce than the amount recovered by the second block's rate. This is a disturbing conclusion and one that may cause the Power Supply Adjustment (PSA) to spiral out of control.

<u>Rate E-32 TOU</u>

The existing rates were last reviewed in 1990, since then the importance and cost of natural gas generation has grown to the present day when the cost of gas fueled electricity now dominates the incremental cost landscape. See Mr. Murphy's Exhibits WJM-4, and WJM-2.

General Service customers today do not have a viable rate choice that has meaningful time of use (TOU) features. Although over 40% of the residential customers are currently on TOU rates. surprisingly only 0.3% of all General Service customers are currently on TOU rates. APS plans to freeze and eliminate almost all existing General service TOU rates (E-21, E-22, E-23, & E-24) This leaves only E-20 (for small "Houses of Worship") The new settlement proposed E-32 TOU currently has no customers.

Despite this unique environment there has been a limited amount of distributed generation (DG).Better designed TOU rates would have resulted in more and better DG projects.

Mr. Murphy testified that there is little understanding by the general public of demand charges ($/kW/Month). (No other party took issue with this observation.) Demand charges are levied against the highest demand level (in kW) measured in any 15 minute period at **anytime** during the month. It makes almost no sense to introduce a new TOU rate with very high demand charges that will comprise over 50% of the total bill. The current customers pay approximately 20% of their bill as demand charges.

The energy charges should bear a much higher portion of the revenue recovery responsibility and on peak energy charges should always reflect the higher cost of producing energy – both at the margin and on average – during the peak hours where system load is traditionally its highest. Moreover, DEAA believes that peak hours should be further split out to peak and shoulder peak hours that better reflect the higher generation costs experienced in these hours. This sends a much better price signal to consumers to alter behavior where possible AND, importantly actually benefit from it through the avoidance of high energy prices.

Unfortunately the proposed E-32TOU rate is primarily designed to reward high load factor customers rather than to provide meaningful price signals.

The proposed Settlement rate E-32TOU is unduly discriminatory to partial requirements customers and will have a severely chilling effect on energy conservation (DSM) and all DG (renewable and CHP). This should be an unacceptable outcome.

The justification for doubling and tripling the demand charges for E-32 TOU was never clearly spelled out other than to say that it provides greater revenue certainty for APS, and that customers that use the system on a more constant basis ought to benefit through lower rates. However, this latter justification was never reconciled with APS's position that the system could not produce any more baseload energy than it currently was producing or with the generally held view that the area will need new generation capacity in the very near future. DEAA submits that rates designed to encourage incremental energy use – especially peak energy use – in this backdrop are wholly inconsistent with sound public policy.

The proposed rate E-32 TOU is a new rate with no customers, therefore right now is a chance to create a new modern TOU rate to provide proper price signals to these commercial and industrial customers.

In his testimony, Mr. Chamberlain indicated that the proposed rate E-32 TOU provided virtually no differentiation of charges based on time of use. He cited the modest difference between on and off peak energy charges as the only significant differentiation. Other parties attempted to rebut Mr. Chamberlain's position by pointing to the "on-peak" period demand charge as substantial differentiation between on and off peak usage.

This attempt to salvage a grossly inadequate rate design fails as these parties either didn't understand the language contained in the E-32R/32TOU or they chose to ignore it. A careful reading of these two schedules shows that monthly billing demands shall be the higher of actual monthly demand; 80% of the highest on-peak demand during the most recent 6 summer months or the contract minimum. The minimum kW described in the E-32 TOU tariff is the higher of the highest kW established during the past 12 months – not time differentiated - or the contract minimum[3]. As a result, a 32 TOU customer is forced to pay monthly demand charges based on the highest demand recorded in the last 12 months – irrespective of whether it occurred in the peak or off-peak period.

Because of the onerous ratchet provisions that face partial requirements customers, a partial requirements customer whose generator served all of its peak loads 99% of the time – taking service almost exclusively during off peak hours – would pay more monthly demand and energy charges than a full service customer with the same load and capacity factor, operating almost entirely during peak periods. While full service customers have a form of ratcheting provision in the calculation of a minimum bill, the charge ($1.75 per kW) is so small that it would almost never be triggered.

None of the supporters of the proposed settlement have offered justification for rates that impose greater costs on partial requirements customers than they impose on full service customers, nor could they. It defies logic. However, this is the consequence of the proposed E 32R/32 TOU rate structure.

The E-32 TOU rate may be the first new general service rate in 14 years. The rate should appeal to small, and medium sized General Service customers, sadly it is just another rate to appeal to large, high load factor users.

It is, apparently, being offered primarily as an alternative to E-32 customers that wish to install their own generation. It is not atypical (and almost always counter-

[3] Interestingly, APS's tariff does not define what or how a contract minimum is established. Nor, apparently, does the tariff require the execution of a formal service agreement.

productive) for a utility to offer a customer class a new rate designed for their use WITHOUT the benefit of any input from those very same customers. And that is what APS has done that with its proposed E-32 TOU/E-32R.

The Commissioners have expressed their clear desire to assure that distributed resources have the opportunity to compete equitably for their role in Arizona's electric future. It makes little sense for this Commission to approve a partial requirements rate that customers generating power - for some or all of their load – are telling you simply won't promote economically efficient on-site generation. DEAA renews its request the ACC reject the changes being proposed in the settlement, or, in the alternative accept the proposed changes we recommend below.

CRITERIA III - Impediments to Customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible.

The settlement pays little attention to the interconnection process. The settlement anticipates and deals with (albeit in a regrettable fashion) rate design issues for on-site generation but offers no relief for the other critical component of on-site and renewable generation – that is, interconnection for parallel operation. For the commercial development of cost effective distributed resources, this is a death knell by causing the time and costs associated with interconnection unnecessarily to grow significantly out of proportion with the economics of the project. This Commission must address this major shortcoming of the settlement.

We all witnessed first hand last July the value that distributed resources operating in parallel with the APS system can bring. Large and Extra-large customers with on-site generation operated their units, avoiding the need for further voluntary curtailments and, perhaps, rolling blackouts. More such resources are needed and interconnection standardization is essential to their development. While voluntary curtailments are laudable, the need for them drains the economic vitality of the community. Companies in the area competing against rivals in other non-constrained areas of the country or world cannot afford the lost production caused by a curtailment or the even the possibility of one. This potentially discourages capital investment in the area.

DEAA proposes below an efficient and comprehensive approach to interconnection standardization that will incorporate the best practices around the country while providing ample opportunity for the Commission to deal with the few legitimate "we don't do it that way in Arizona" issues that may arise. Experience around the nation suggests that so-called local differences are red herrings designed to preserve the status quo.

DEAA wants to stress the need for a streamlined interconnection process for operating in parallel with the APS distribution system. The attempt to accomplish this in 1999 bore little fruit, while consuming substantial resources on the part of the DG community. Despite a lengthy report summarizing the effort, little was accomplished and even less put into action. DEAA does not believe that picking up where that effort left off is efficient or likely to be helpful. Much has changed on the interconnection standardization front including the adoption of IEEE 1547.

As numerous witnesses testified moreover, several major states have already implemented comprehensive interconnection standards and processes. Arizona should benefit from review of those standards and not try to "reinvent the wheel.".

Basically a standardized and efficient interconnection approval process should reflect the true net costs of interconnection. The best answer remains for the ACC to standardize the interconnection requirements to the extent feasible rather than reinventing the process for every project.

Interconnection standards serve to simplify the interconnection process for a customer's small scale on site generation. DEAA believes that the Texas program is best suited for application to the APS system. We therefore propose using the Texas program as a 'straw man' for the interconnection workshops. The ACC may create a 'straw man' interconnection model based on the Texas standards as a rebuttable presumption for later workshops. This 'straw man' would be used to discuss what minimal changes might be reasonably applied to the 'straw man' in order to meet legitimate local differences. Thus the Texas standard contemplates "off-the-shelf" installations of DG projects. These would be subject to any site-specific impediments.

The Public Utility Commission of Texas (PUCT) expressed the following intent: "The goal was to simplify and standardize utility interconnection protocols and to develop proposed tariff rule language that could apply to all distributed generation facilities seeking to interconnect with the utilities."

They actually incorporated that intent into the distributed generation regulations themselves: "The purpose of this section is to clearly state the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation TAC 25.211(b). This section will ensure that applicants are aware of the technical interconnection requirements and utility interconnection policies and practices. This section will also provide applicants with an understanding of the process and information required to allow utilities to review and accept the applicant's equipment for interconnection in a reasonable and expeditious manner".

First the Texas standard defines "Distributed Generation" to include projects of up to 10 MW. 16 TAC 25.211(c)(10). We encourage a similar approach in Arizona.[4].

Next while different jurisdictions adopt slightly varying approaches, there is some consensus on the issues to be addressed in the interconnection process. The first is the application process. The process may include a standard application form and specify application fees, pre-interconnection studies and costs, time periods for processing for interconnection requests, and a method to resolve interconnection disputes.

Texas rules establish a short time limit for the utility to respond to the customer that the application has been completed adequately.

Along with a development of a standard application form for initiating a Distributed Generation (DG) project, a standard form of interconnection agreement should also follow. See PUCT Project No. 22318 (September 2000), Attachment A "Agreement for Interconnection and Parallel Operation of Distributed Generation.

Next the interconnection process should provide for safety, but should also specify the general interconnection and protection requirements. See 16 TAC 25.212(b) through (e); and Section 4, California Rule 21, General Interconnection and Protection Requirements.

The ACC should also consider authorizing precertification of DG equipment. Texas has developed perhaps the most *avant garde* approach to testing and certification of DG equipment. The PUCT regulations authorize pre-certification of equipment to function in DG facilities. Equipment Pre-Certification, 16 TAC 25.211(k). Once certified no further review of the design is required prior to installation. This expedites installation of DG facilities and eliminates redundant and costly utility equipment evaluation.

See "Requirements for Pre-Certification of Distributed Generation Equipment by a Nationally Recognized Testing Laboratory"; PUCT Project No. 22318 (September 2000).

Note too that the Department of Energy in conjunction with a number of state energy agencies is also developing DG laboratory, field testing, and monitoring protocols. www.dgdata.org.

Next the cost of any necessary utility study must be capped as part of the standards so the real cost of the interconnection is determinable at an early stage so that a supplier can know his costs at an early stage. Moreover, interconnection costs should be detailed in a manner sufficient to examine the legitimacy of the costs. Interconnection costs should not take into consideration those costs that would have otherwise been incurred as part of normal retail service to the customer.

Texas for example, allows no pre-interconnection study fees to be charged to DG projects of up to 500 kW which contribute not more than 25% of the maximum potential short circuit current on a single radial feeder. 16 TAC 25.211(g)(1). For all DG applications, the utility must complete the study within four weeks of the study request. 16 TAC 25.211(g)(2)(A) and 25.211(i)(1). In fact in Texas the actual DG facility must be interconnected to the utility's system within four weeks for pre-certified equipment; and within six weeks for all other equipment "after the utility's receipt of a completed application". 16 TAC 25.211(m)(1). Thus the Texas standard contemplates "off-the-

[4] California has also adopted a limit of 10 MWs for its process.

shelf" installations of DG projects. Of course, the installations would be subject to any site-specific impediments[5].

Dispute Resolution Requirements. Finally a dispute resolution mechanism helps promptly resolve any interconnection disputes between the customer and the utility. For example in Texas the public utility commission may step in and resolve any dispute as between the customer and utility. The PUCT attempts initially to resolve disputes informally, within 20 business days in Texas. See Interconnection Disputes, 16 TAC 25.211(o); and Section 7, Dispute Resolution, California Rule 21.

> Should informal dispute resolution fail, then the matter is transferred onto thestandardbusiness calendar of the respective commission for resolution at an upcoming commission meeting. The presence of a dispute resolution process however helps speed he interconnection process for the parties.

The Federal Energy Regulatory Commission (FERC) agrees with the need for standardization. Quoting from the Introduction of its Notice of Proposed Rulemaking in Docket No. RM02-12-000, Standardization of Small Generator Interconnection Agreements and Procedures dated July 24, 2003 (104 FERC 61,104), FERC stated that:

"Entities seeking to interconnect generators have been hindered by lack of standard interconnection procedures and agreements. Standard Interconnection procedures limit opportunities for public utilities that own both generation and transmission to favor their own generation and help produce just and reasonable interconnection charges for generators. A standard interconnection agreement reduces market entry costs for generators and offers them access to regional energy markets on standard terms."

[5] See the Texas website http://www.powertochoose.org/resources/glossary.asp#p.

.CRITERIA IV - All generators should be treated fairly – large and small.

The settlement provides for a prohibition on APS building large merchant facilities. However, no such prohibition exists for small on-site generation and renewable projects. DEAA submits that the opportunity for self-dealing within APS is much greater for smaller units than it is for large ones. Surely this Commission should afford the "little guys" as much protection as the large generators.

The self-build moratorium in the settlement provides a strong signal that the Arizona Corp Commission believes that independent power production is an effective alternative to the traditional vertically integrated utility. FERC's comment above in CRITERIA III confirms this aspect.

CRITERIA V - Proposals, if implemented, should not interfere with the Commission public policy goals.

The DEAA believes this Commission has enunciated clear goals with respect to on-site generation, renewable energy, customer choice and the need for competitive influences in the market place. The value these resources can provide was witnessed first hand last summer during the West Wing substation disaster. The availability of DG during that period may have been what allowed the system to maintain some modicum of reliability without involuntary load shedding.

DEAA believes that the rates in the proposed settlement will almost certainly curtail any significant new commercially-viable development of distributed resources and renewable projects.

DEAA RECOMMENDATIONS

The DEAA proposes below a small number of recommendations for Commission consideration and implementation. These proposals are, in our opinion, reasoned approaches to deal surgically with our deep concerns about the proposed settlement's likely impact on customer-owned distributed generation and renewables. Moreover, we believe that our proposals have little or no impact on the any of the other components of the settlement – the provisions of which we have not commented on.

DEAA urges this Commission to consider these proposals as an essential step towards increased system reliability, lower overall customer costs of electricity and increased customer choice.

RATE DESIGN

DEAA proposes that the Commission adopt the proposed rate design detailed below as an alternative to E-32 TOU and E-52.

Since the other parties believe that E-32 TOU provides the best rate structure for partial requirements customers, a migration of these customers from E-32 to e-32R/32 TOU has already been anticipated in the settlement. Further, since E-32 TOU currently has no customers, no other party will be harmed if partial requirements customers are offered a service alternative to E-32R/E-32 TOU.

The proposed rate would be an experimental rate for partial requirements customers only and could limit total enrollment to mitigate over or under recoveries by APS. We would propose a limit of 50 MWs of new customer load each year for 5 years – both generation and supplemental load. DEAA recommends that any over or under recoveries created (and confirmed by this Commission at a later time) as a consequence of this proposal be rolled into the PSA for recovery. What little amounts might accumulate will almost certainly be dwarfed by the other components of the PSA.

DEAA has examined the SRP E-32(coincidentally) rate from Salt River Project (SRP). As this Commission is aware, SRP has load characteristics very similar to APS. Moreover, its cost structures and generating plant profiles are very similar as well.

Therefore, our proposal is to mimic the SRP rate E-32 for our proposed experimental rate. It seems to us that it has a reasonably good chance of providing proper price signals while assuring appropriate revenue recovery – given the strong similarities discussed above.

Specifically, the rate has three daily time periods – Peak, Shoulder peak, and off peak. Each period has its own demand and energy charges based on the costs based on the time of the day. By breaking up the day into more periods, average pricing of energy begins to look closer to the marginal cost and the deviations between average costs and highest costs are removed. Consumers pay a price much closer to the actual cost of production with SRP rate E-32, which is summarized below..

The time periods are as follows for summer and winter:

Summer On-peak 2:00 pm to 7:00 pm Weekdays
Summer Shoulder-peak 11:00 am to 2:00 pm and 7:00 pm to 11:00 pm Weekdays
Summer Off-Peak all other hours

Winter On-peak 5:00 am to 9:00 am Weekdays
Winter Shoulder-peak 5:00 pm to 9:00 pm Weekdays
Winter Off-peak All other hours.

The published demand charges are as follows:

Summer
May 1 - October 31

Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$2.20	$0.06	--
Transmission Delivery	$2.46	$0.31	--
Competitive Customer Service	$0.04	$0.00	--
Ancillary Services 1 and 2	$0.09	$0.08	--
Total	$4.79	$0.45	--

Winter
November 1 - April 30

Per kW Charges (all kW)	On-Peak	Shoulder-Peak	Off-Peak
Distribution Delivery	$1.66	$0.04	--
Transmission Delivery	$2.00	$0.22	--
Competitive Customer Service	$0.04	$0.00	--
Ancillary Services 1 and 2	$0.07	$0.05	--
Total	$3.77	$0.31	--

The energy charges (which can be found on the website listed below) are higher than the APS rate E-32 when the SRP fuel adjustment of approximately 2.5¢/kWh is added.

For more detailed rate information go to:

www.srpnet.com/prices/pdfx/BusE32Nov04.pdf

INTERCONNECTION

Interconnection Standards- Purpose. Interconnection standards serve to simplify the interconnection process for customer small scale on site generation. A number of states and public organizations have developed such protocols. DEAA believes that the Texas program is best suited for application to the APS system and we propose using it as a 'straw man' for the interconnection workshops. And, the Texas standard contemplates "off-the-shelf" installations of DG projects. The installations would be subject to any site-specific impediments.

Alternatively, the DEAA believes that the provisions of California rule 21 serve as a competent second choice basis for DG standards in Arizona.

DISTRIBUTED GENERATION PROGRAM

DEAA recommends that the Commission consider a program to install "self generation" to reduce the electricity on the power grid.

On July 3, 2001, the California Public Utilities Commission initiated a $125 million per year Self-Generation Incentive Program to encourage generation systems to supply all or a portion of their energy needs.

However, we at DEAA recommend **no incentives** for the State of Arizona. We propose a 25 MW per year Program for Arizona every year before 2015. This would add 250MW of Self-Generation (DG) to the APS system.

We intend that the DG Program be developed by the ACC as an addition to that offered in the settlement. The DG program above does not replace nor change the 100MW Renewables program that is already part of the Settlement.

We believe that all distributed renewables should be considered as DG. We have added all Technologies defined by DOE as Renewables into the eligible technologies so as to have a complete list as follows:

SOLAR, BIOMASS, BIOGAS, WIND, HYDRO, GEOTHERMAL, BIOFUELS

DEAA advocates that the ACC use the DOE definition of Distributed Generation. Thereafter, if DOE adds a technology to their list, the ACC need not address the issue for new possibilities. See www.eere.energy.gov. for more data about the DOE definition of DG.